AMERICAN MIDSTREAM, LLC
ATMORE PLANT
ATMORE, ESCAMBIA COUNTY, AL
FACILITY NO.: 502-0092

ENGINEERING ANALYSIS

Project Description

On January 28, 2010, the Department received an air permit application for a new natural gas treating and processing plant to be operated by American Midstream, LLC. Additional information regarding the permit application was requested on February 1, 2010. A complete application was received on February 4, 2010. On December 3, 2009, a Greenfield site inspection was conducted at this site during the Greenfield site inspection of the Mason 36-14 No. 1 Oil and Gas Production Well operated by Venture Oil and Gas, Inc. Venture Oil and Gas, Inc. allotted five acres of land adjacent to its Fountain Farm 2-4 No. 1 Oil and Gas Production Well to be used by American Midstream, LLC for this gas plant. Neither the gas plant nor the well will be under common ownership.

The Atmore Plant would be located in Section 2, Township 2 North, Range 6 East in Atmore, Escambia County, AL. The plant would be expected to treat and process up to 2.5 MMscf/day of natural gas. Currently the Atmore Plant plans to process gas from 2 nearby wells, the Mason 36-14 No. 1 Well which is a permitted sour natural gas well and the Fountain Farm 2-4 No.1 Well which is a non-permitted sweet gas well. The inlet gas is expected to contain 0.193 mol% (~1930 ppmv) of hydrogen sulfide (H_2S).

Process Description

Upon entering the plant the natural gas from the incoming wells would be combined and passed though a metering station to measure the flowrate of gas entering the plant. The gas would then be sent through an inlet gas-liquid separator (gravity is used for separation) to produce a condensate and water mixture and a sour gas stream. The condensate and water mixture would be sent to storage until it is sold and trucked offsite.

The sour gas stream exiting the separator would pass though an amine contactor to remove H_2S and carbon dioxide (CO_2) impurities from the sour gas. A sweet gas stream (~0 mol % H_2S) and an acid gas stream would be produced during the sweetening process. The acid gas stream would be metered and sent to the flare to be combusted; however, the sweet gas would be further processed. The sweet gas would then pass through a glycol dehydration system which would use ethylene glycol (EG) to remove the associated water from the gas. The dried sweetened gas would then pass through a refrigeration plant where the gas stream would be compressed and cooled to allow for the heavy natural gas liquids (NGLs) to condense and drop out of the gas. The NGL stream would then be sent to a KOH treater where sulfur compounds remaining in the NGLs would be removed prior to being sent to storage. The line heater would be used for further separation as required; however, it is not fired. The NGLs would be stored until sold and trucked offsite. The gas stream exiting the refrigeration plant would be sent to the sales pipeline or used as assist gas. Sour gas vapors from the condensate storage vessel and condensate loading rack would be captured by a closed vent system and sent to the flare along with the acid gas from the amine sweetening unit for combustion.

Emissions

	***Total Emissions for American Midstream, LLC-Atmore Plant* (Tons/yr)**					
Emission Source	**PM**	**SO_2**	**NO_X**	**CO**	**VOC**	**Formaldehyde**
Flaring FWS Continuously	-	1.49E+02	3.26E+01	1.77E+02	1.92E+02	-
Engine	6.37E-02	0.00E+00	1.48E+01	2.49E+01	1.98E-01	1.37E-01
Total	**6.37E-02**	**1.49E+02**	**4.74E+01**	**2.02E+02**	**1.92E+02**	**1.37E-01**
(Requested Limits)	-	*95 TPY*	-	*95 TPY*	*95 TPY*	-

Regulations

The following regulations may be applicable to the Atmore Plant:

ADEM Regulations

ADEM 335-3-4-.01(a) and (b) Visible Emissions, Control of Particulate Emissions

ADEM 335-3-4-.01(a) states that no person shall discharge into the atmosphere from a source of emission, particulate of an opacity greater than that designated as twenty percent (20%) opacity, as determined by a six minute average.

ADEM 335-3-4-.01(b) states that during one six minute period in any sixty minute period a person may discharge into the atmosphere from any source of emissions, particulate of an opacity not greater than that designated as forty percent (40%) opacity.

This regulation would be applicable to the engine and the re-boilers for the amine sweetening unit and the glycol dehydration unit. However, since sweet gas would be burned as fuel in these units, it would not be necessary to perform daily monitoring on these units.

ADEM 335-3-4-.03, Fuel Burning Equipment

This regulation covers particulate emissions from fuel burning equipment. Since the line heater for the facility would not be fired, it would not be subject to this regulation. The 1.5 MMBtu/hr amine reboiler and the 0.5 MMBtu/hr glycol reboiler would be subject to this regulation. However, since the combustion of natural gas should result in very low particulate emissions, the potential particulate matter (PM) emissions for both heaters would be less than the 9.81 Ton/yr (TPY) allowed for a source located in a Class 2 County. Also, both units would be considered insignificant activities under ADEM's definition of insignificant activities. Because the units' capacity would be greater than or equal to 0.5 MMBtu/hr, but less than 5 MMBtu/hr and they are not subject to a NSPS, NESHAP or MACT regulation, they would not be subject to this regulation.

ADEM 335-3-5-.01(b), Fuel Combustion

This regulation covers fuel combustion sulfur limitations for Category II counties, which includes Escambia County. Under this regulation, the 0.5 MMBtu/hr glycol reboiler and 1.5 MMBtu/hr amine reboiler would not be allowed to emit more than 4.0 lb/MMBTU of sulfur compounds. However, since the units are insignificant activities, no monitoring would be required for sulfur dioxide (SO_2) from these units.

ADEM 335-3-5-.03(1-2), Petroleum Production

These regulations would require that process gas streams containing greater than 0.10 grains per standard cubic foot (scf) of hydrogen sulfide (H_2S) be properly burned to maintain a ground concentration of less than 20 ppb beyond property limits, as averaged over a 30 minute period. Since the process gas stream at the Atmore Plant will contain greater than 0.10 grains/scf of H_2S (~160 ppmv H_2S), all facility emission points would be subject to this regulation. However, since the heaters and engine burn primarily sweetened natural gas for fuel, these units should emit essentially zero H_2S.

The flare would burn sour gas vapors from the storage tanks and acid gas from the amine sweetening unit during normal operation or sour gas when the amine unit is down; therefore, this unit would be subject to these regulations. In a Category II County, as long as the available sulfur does not exceed 10 Long Tons per day (Ltons/day), SO_2 emissions are unlimited. However, because the facility has requested to become a synthetic minor source for criteria pollutant their facility-wide SO_2 emissions are limited to 95 tons per 12 consecutive months.

Compliance with this regulation would be met by burning all process gas containing 0.10 grains/scf of H_2S to the flare. Monitoring shall be in the form of maintaining the H_2S feed rate to flare at 500 lb of H_2S/hr and testing the process gas streams for its H_2S content and Btu Content on a monthly basis.

ADEM 335-3-14-.04 Prevention of Significant Deterioration (PSD) Permitting

This regulation applies to the construction of any new major stationary source or any project at an existing major stationary source. The Atmore Plant would be a new stationary source; however, it would not be considered a major source under this regulation because the potential emissions from the plant would not be expected to exceed the 250 TPY PSD threshold. Therefore, this project is not subject to a PSD review.

ADEM 335-3-16 Major Source Operating Permit

The Atmore Plant would have the potential to emit greater than 100 tons per year of criteria pollutants (specifically SO_2, CO, and VOC) provided that the full well stream is flared continuously. The potential uncontrolled emissions for the plant are found in the emissions section. The facility has requested a limit of 95 tons per twelve consecutive months to maintain the SO_2, CO, and VOC emissions below the major source threshold for criteria pollutant. The limit would allow the facility to be a synthetic minor source of criteria pollutants instead of a major source with respect to this regulation.

The plant does not have the potential to emit greater than 10 TPY of a single hazardous air pollutant (HAP) or 25 TPY for a combination of HAPs. Therefore, the plant would not be a major source of criteria pollutants or HAPs under this regulation.

Air Toxic Program

No Air Toxics review would be warranted due to the relatively low amount of HAPs emissions from this facility.

Class I Area

The nearest Class I Area to the Atmore Plant would be the Brenton Wildlife Refuge; however, the plant would be located more than 100 km from this area.

Federal Regulations

40 CFR 60, Subpart A General Provisions

The proposed facility would be subject to the requirements of this subpart, provided that it is subject to the applicable requirements of one of the subpart found in 40 CFR Part 60.

40 CFR 60, Subpart K_b, "Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction, or Modification Commenced After July 23, 1984"

Only the 8,820 gallon condensate storage tank (T-01) would be subject to this regulation. However, §60.110b (d)(4) states that vessels with a design storage capacity of less than, or equal to, 1590 m^3 (420,000 gallons) used for petroleum or condensate stored, treated, or processed prior to custody transfer are exempt from this regulation. Therefore, this storage tank would not have to meet the requirements under this subpart.

The pressurized NGL storage tanks would not be subject to this subpart. This storage vessel would be considered a trivial activity under ADEM's definition.

ADEM Admin. Code R. 335-3-10-.02(48) and 40 CFR 60 Subpart KKK, *"Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants"*

Applicability

The Atmore Plant would meet the definition of an onshore natural gas processing plant, as defined in §60.631 of this subpart, because natural gas liquids (NGL) would be extracted from the field gas. This subpart would be applicable to affected facilities at an onshore natural gas processing plant. Affected facilities would include compressors in VOC service or in wet gas service and the group of all equipment, except reciprocating compressors in wet gas service, within a process unit that commences construction, reconstruction, or modification after January 20, 1984 (§60.630 Subpart KKK). The Atmore Plant would be subject to this regulation. Since a dehydration unit, sweetening unit and liquefied natural gas unit would be located at the Atmore Plant, they would also be covered under this subpart (§60.630 (e)).

Emission Standards

To demonstrate compliance with the applicable requirements of this subpart, emission standards found in §60.632 of Subpart KKK shall be met, except as provided in 40 CFR §60.633 of this subpart. The emission standards for Subpart KKK refer to 40 CFR 60, Subpart VV-"*Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry*".

Compliance and Performance Test Methods and Procedures

Compliance with the emissions standards for 40 CFR 60 Subpart KKK shall be demonstrated through the review of records and reports, review of performance test results, and inspection using the methods and procedures specified in §60.485 of Subpart VV, except as specified in §60.633(h) of Subpart KKK (§60.632(d) of Subpart KKK and §60.482-1(b) of Subpart VV).

Emission Monitoring

Emission monitoring shall be demonstrated by meeting the inspection and monitoring requirements specified in §60.482-1 through §60.482-10 of 40 CFR 60 Subpart VV. Alternative methods of monitoring may be elected as specified in either §60.483-1 or §60.483-2 of Subpart VV (§60.632 (b) of Subpart KKK).

Because the Atmore Plant would be a non-fractionating plant (it would not separate the NGLs into natural gas products such as ethane or butane) and it would not have a design capacity to process 10 MMscf/day or more of field gas, it would be exempt from the routine monitoring requirements found in the following subparts (§60.633 (d)):

- §60.482-2(a)(1) of Subpart VV
- §60.482-7(a) of Subpart VV
- §60.633 (b)(1) of Subpart KKK

Sampling connection systems would also be exempt from the requirements found in §60.482-5 of Subpart VV (§60.633 (c) of Subpart KKK).

Recordkeeping and Reporting Requirements

- Compliance with the recordkeeping requirements shall be met by complying with §60.486 of Subpart VV and as specified in §60.633 and §60.635 of Subpart KKK (§60.632 (e) of Subpart KKK).

- Compliance with the reporting requirements shall be met by complying with §60.487 of 40 CFR Subpart VV and as specified in §60.633 and §60.636 of Subpart KKK (§60.632 (e) of Subpart KKK).

    - A Leak Detection and Repair (LDAR) summary report shall be submitted to the Department to demonstrate compliance with the requirements of 40 CFR 60 Subpart KKK (40 CFR §60.487 of Subpart VV).

    - The report shall be submitted semi-annually on calendar basis according to the following reporting schedule:

Reporting Period	Submittal Date
January 1st through June 30th	*July 31st*
July 1st through December 31st	*January 31st*

40 CFR 60.18

Since the flare would be used as a control device to control emissions from the amine sweetening unit, which is covered under 40 CFR 60 Subpart KKK, the flare would be required to be smokeless. Additional requirements for the flare would be found under 40 CFR §60.18 (§60.482-10(d)).

40 CFR 60, Subpart LLL, "Standards of Performance for Onshore Natural Gas Processing: SO_2 Emissions"

This subpart applies to affected facilities that process natural gas including each sweetening unit located at onshore gas treatment facilities constructed, reconstructed, or modified after January 20, 1984. Per §60.640(b), facilities that have a design capacity less than 2 Ltons/day of H_2S in the acid gas (expressed as sulfur) are required to comply with the recordkeeping requirement found in §60.647(c), but are not required to comply with §60.642 through §60.646. The Atmore Plant would have a design capacity less than 2 Ltons/day of H_2S in the acid gas; therefore, they would only be subject to the requirement to maintain, for the life of the facility, an analysis demonstrating that the facility's design capacity is less than 2 LTons/day of H_2S expressed as sulfur.

40 CFR 60 Subpart JJJJ, "Standards or Performance for Stationary Spark Ignition Internal Combustion Engines (SI ICE)"

This regulation would be applicable to owners and operators of stationary SI ICE engines in which construction commenced after June 12, 2006. Applicability to this regulation also depends on the date of manufacture for the unit. Since the 180 HP refrigeration compressor engine has a maximum engine power less than 500 HP, it was manufactured prior to July 1, 2008 (estimated manufacture date given as prior to January 1994), and it has not been reconstructed, the unit would not be subject to the requirements of this subpart (§60.4230(a) (4) (iii)).

40 CFR 63, Subpart A, "General Provisions"

The proposed facility would be subject to the requirements of this subpart, provided that it is subject to the applicable requirements of one of the subpart found in 40 CFR Part 63.

40 CFR 63, Subpart HH, "National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities

This subpart applies to facilities that are a major source or area source of HAPs (§63.760(a)(1)) and either process, upgrade, or store hydrocarbon liquids prior to the point of custody transfer (§63.760(a)(2)) or process, upgrade, or store natural gas prior to the point at which natural gas enters the natural gas transmission and storage source category or is delivered to a final end user (40 CFR §63.760(a)(3)).

As shown in the emissions section, the total HAPs from this facility would not be expected to exceed either of the major source thresholds for HAPs. A major source of HAPs requires a potential to emit 10 TPY of one HAP or 25 TPY of a combination of HAPs (§63.2). The Atmore Plant will produce hydrocarbon liquids, produce and process natural gas, and it would be an area source of HAPs; therefore, it would be subject to this subpart.

In order for the Atmore Plant to have an affected source under this subpart for an area source, it would have to be equipped with a tri-ethylene glycol (TEG) dehydration unit (§63.760(b)(2)). The plant would be equipped with an ethylene glycol (EG) dehydration unit, not a TEG dehydration unit. TEG would be used to heat the EG for regeneration; however, the TEG would be in a closed loop system which would result in no emissions. Therefore, the plant would not be subject to the applicable requirements of this subpart.

40 CFR 63, Subpart ZZZZ, "National Emissions Standards for Hazardous Air Pollutants (NESHAP) for Stationary Reciprocating Internal Combustion Engines (RICE)"

The requirements of this subpart (also referred to as MACT 4Z or Engine MACT) would apply to any internal combustion engine that is located at a site that would be a major source of HAPs or an area source of HAPs. A major source of HAPs requires 10 TPY of one HAP or 25 TPY of a combination of HAPs (40 CFR §63.6585 (b)). An area source of HAPs, under Subpart ZZZZ, is defined as a source that is not a major source (40 CFR §63.6585(c)). The Atmore Plant would be an area source of HAPs because it does not meet the definition of a major source.

Since the refrigeration compressor engine would be located at an area source of HAPs and it would be constructed after June 12, 2006, it would be considered a new stationary RICE (40 CFR §63.6590(a)(2)(iii)). However, an affected source that is a new or reconstructed stationary RICE located at an area source would be required to meet the requirements of this part by meeting the requirements of 40 CFR 60 Subpart JJJJ for spark ignition engines and no further requirements apply for such engines under this part at this time (§63.6590(c)).

Recommendations

I recommend that American Midstream, LLL be issued Synthetic Minor Operating Permit (SMOP) No. 502-0092-X001 for the facility-wide emission sources and SMOP No. 502-0092-X002 to cover VOC emissions from onshore natural gas processing plants. The Atmore Plant should be able to meet the applicable state and federal regulations associated with this facility.

____________________________ February 10, 2010

Harlotte M. Bolden-Wright — Draft Date

Industrial Minerals Section

Energy Branch

ATMORE PLANT
FACILITY NO.: 502-0092

ATTACHMENT A:

CALCULATIONS

Part A –FLARE CALCULATIONS

The flare calculations are based on continuous flaring of the full well stream. The information found in Table A-1 was provided by American Midstream LLC. in their permit application. The rated heat capacity would be determined in Equation I using the gas flowrate and heat content provided in Table A-1.

Flowrate *(scf/hr)*	**Heat Content** *(Btu/scf)*	**H_2S** *(mole %)*	**Rated Heat Capacity** *(MMBtu/hr)*
104,167	1,050	0.193	109.38

Table A-1: Gas Analysis Data

$$Rated\ Heat\ Capacity\left(\frac{MMBtu}{hr}\right) = Flowrate\left(\frac{scf}{hr}\right) * Heat\ Content\left(\frac{Btu}{scf}\right) * \left(\frac{MMBtu}{10^6\ Btu}\right)$$

[Equation I]

- Calculating NO_X and CO Emissions

The AP-42 Emission Factors for flares found in Table 13.5-1 of the Industrial Flares Section are shown in Table A-2. These emission factors would be used to determine CO and NO_X emissions.

Flare AP-42 Emission Factors *(lb/MMBtu)*	
NO_X	**CO**
0.068	0.37

Table A-2: AP-42 Emission Factors for Flares

Equation II would be used to determine the CO and NO_X emissions produced from the flare. The rated heat capacity and AP-42 emission factors are found in Tables A-1 and A-2, respectively.

$$Emissions\left(\frac{lb}{hr}\right) = Rated\ Heat\ Capacity\left(\frac{MMBtu}{hr}\right) * AP-42\ Emission\ Factor\left(\frac{lb}{MMBtu}\right)$$

[Equation II]

Table A-3 shows the potential NO_X and CO emissions from the flare.

Potential NO_X and CO Emissions			
(lb/hr)		*(Ton/year)*	
NO_X	**CO**	**NO_X**	**CO**
7.44E+00	**4.05E+01**	**3.26E+01**	**1.77E+02**

Table A-3: Potential CO and NO_X Emissions

- Calculating SO_2 Emissions

Since the gas analysis shows that the gas stream contains 0.193 mol% of H_2S, the emissions would be calculated using Equation III to determine sulfur dioxide (SO_2) emissions from the flare.

$$Amount\ of\ SO_2\left(\frac{lb}{hr}\right) = 1.689\left(\frac{lb}{Mscf}\right) * H_2S\,(mole\%) * Flowrate\left(\frac{Mscf}{hr}\right)$$

[Equation III]

$$= 1.689\left(\frac{lb}{Mscf}\right) * 0.193\ mole\%\ H_2S * 1.04E+02\frac{Mscf}{hr} = 3.40E+01\frac{lb}{hr}$$

- Calculating VOC Emissions

In order to estimate the potential VOC emissions, the following assumptions were made:

a. the gas molecular weight = 20 lb/lbmol
b. the VOC mass fraction = 0.40
c. the flare is 98% efficient

The potential VOC emissions would be calculated using Equation IV where the flowrate is given in Table A-1.

$$VOC\ Emissions\left(\frac{lb}{hr}\right) = \left(\frac{Flowrate\left(\frac{scf}{hr}\right) * 20\,\frac{lb}{lb - mol}}{380\,\frac{scf}{lb - mol}}\right) * 0.40 * (1 - 0.98)$$

[Equation IV]

$$= \left(\frac{104{,}167 \frac{scf}{hr} * 20 \frac{lb}{lb - mol}}{380 \frac{scf}{lb - mol}} \right) * 0.40 * (1 - 0.98) = 4.39E + 02 \frac{lb}{hr}$$

- Total Potential Emissions from the Flare

Table A-4 shows the total potential emissions for the flare assuming constant flaring. The emissions are converted to tons per year by multiplying by a conversion factor of 4.38.

Flare Potential Emissions *(Ton/yr)*			
SO_2	**NO_X**	**CO**	**VOC**
1.49E+02	**3.26E+01**	**1.77E+02**	**1.92E+02**

Table A-4: Total Potential Emissions from the Flare

Part B –ENGINE CALCULATIONS

The potential emissions from the refrigeration compressor engine are based on AP-42 emission factors (EF) for four stroke rich burn engines found in Section 3.2 for Natural Gas-fired Reciprocating Engines. The emission factors are found below in Table B-1. The manufacturer's conversion factor (CF) of 8,500 Btu/HP-hr was also included in the application.

AP-42 Emissions Factors *(lb/MMBTU)*				
PM	**NO_X**	**CO**	**VOC**	**Formaldehyde**
9.50E-03	2.21E+00	3.72E+00	2.96E-02	2.05E-02

Table B-1: 4SRB Engine Emission Factors

- Calculating PM, NO_X, CO, VOC and HAPs Emissions

Potential emissions would be determined using the AP-42 emission factors found in Table B-1 and the manufacturer's conversion factor in Equation V. Formaldehyde is representative of HAPs emissions for four stroke rich burn engines since it is present in the highest concentration. SO_2 emissions from the engine should essentially be negligible since the engine would use sweetened natural gas as its fuel source.

$$Emissions\left(\frac{lb}{hr}\right) = AP\text{-}42\ EF\left(\frac{lb}{MMBtu}\right) * Manufacturer's CF\left(\frac{Btu}{HP\text{-}hr}\right) * EngineRating(HP) * \frac{1MMBtu}{10^6\,Btu}$$

[Equation V]

The emissions calculated using Equation V are converted to units of tons per year by multiplying by a conversion factor of 4.38. The potential emissions from the refrigeration engine are given below in Table B-2.

Refrigeration Compressor Engine Potential Emissions *(Tons/yr)*						
	PM	**SO_2**	**NO_X**	**CO**	**VOC**	**Formaldehyde**
Engine	**6.37E-02**	**0.00E+00**	**1.48E+01**	**2.49E+01**	**1.98E-01**	**1.37E-01**

Table B-2: Potential Engine Emissions

Part C–FACILITY WIDE EMISSIONS

The potential emissions from the Atmore Gas Plant are found in Table C-1. However, the facility has requested limits of 95 tons per twelve consecutive months for emissions exceedinf the 100 TPY major source threshold for criteria pollutants.

Potential Facility-Wide Emissions **(Tons/yr)**						
	PM	**SO_2**	**NO_X**	**CO**	**VOC**	**Formaldehyde**
180 HP 4SRB Engine	6.37E-02	0.00E+00	1.48E+01	2.49E+01	1.98E-01	1.37E-01
Process Flare	-	1.49E+02	3.26E+01	1.77E+02	1.92E+02	-
Total PTE	**6.37E-02**	**1.49E+02**	**4.74E+01**	**2.02E+02**	**1.92E+02**	**1.37E-01**

Table C-1: Potential Emission from the Atmore Plant

ATMORE PLANT
FACILITY NO.: 502-0092

ATTACHMENT B:

DRAFT PROVISOS

SYNTHETIC MINOR OPERATING PERMIT

PERMITTEE: AMERICAN MIDSTREAM, LLC

FACILITY NAME: ATMORE PLANT

LOCATION: ATMORE, (ESCAMBIA COUNTY), AL

PERMIT NUMBER	DESCRIPTION OF EQUIPMENT, ARTICLE OR DEVICE
502-0092-X001	**Facility-Wide Emissions for Natural Gas Treating and Processing Plant** (E-1) 180 HP 4SRB Refrigeration Compressor Engine (FLARE) Process Flare w/closed system (T-01) 8,820 Gallon Condensate Storage Tank Condensate Loading Rack <u>Trivial or Insignificant Activities</u> (HT-01) 1.5 MMBtu/hr Amine Reboiler (HT- 02) 0.5 MMBtu/hr Glycol Reboiler

In accordance with and subject to the provisions of the Alabama Air Pollution Control Act of 1971, as amended, Ala. Code §§22-28-1 to 22-28-23 (2006 Rplc. Vol. and 2007 Cum. Supp.) (the "AAPCA") and the Alabama Environmental Management Act, as amended, Ala. Code §§22-22A-1 to 22-22A-15 (2006 Rplc. Vol. and 2007 Cum. Supp.), and rules and regulations adopted there under, and subject further to the conditions set forth in this permit, the Permittee is hereby authorized to construct, install and use the equipment, device or other article described above.

ISSUANCE DATE: DRAFT February 24, 2010

Alabama Department of Environmental Management

American Midstream, LLC-Atmore Plant
ATMORE, ALABAMA
(PERMIT NO. 502-0092-X001)
PROVISOS

1. This permit is issued on the basis of Rules and Regulations existing on the date of issuance. In the event additional Rules and Regulations are adopted, it shall be the permit holder's responsibility to comply with such rules.

2. This permit is not transferable. Upon sale or legal transfer, the new owner or operator must apply for a permit within 30 days.

3. A new permit application must be made for new sources, replacements, alterations or design changes which may result in the issuance of, or an increase in the issuance of, air contaminants, or the use of which may eliminate or reduce or control the issuance of air contaminants.

4. When safe and practical, each point of emission will be provided with sampling ports, ladders, platforms, and other safety equipment to facilitate testing performed in accordance with procedures established by Part 60 of Title 40 of the Code of Federal Regulations, as the same may be amended or revised.

5. In case of shutdown of air pollution control equipment for scheduled maintenance for a period greater than **4 hour,** the intent to shut down shall be reported to the Air Division at least 24 hours prior to the planned shutdown, **unless accompanied by the immediate shutdown of the emission source.**

6. In the event there is a breakdown of equipment in such a manner as to cause increased emission of air contaminants for a period greater than **4 hour**, the person responsible for such equipment shall notify the Air Division within an additional 24 hours or next work day and provide a statement giving all pertinent facts, including the duration of the breakdown. The Air Division shall be notified when the breakdown has been corrected.

7. This process, including all air pollution control devices and capture systems for which this permit is issued, shall be maintained and operated at all times in a manner so as to minimize the emissions of air contaminants. Procedures for ensuring that the above equipment is properly operated and maintained so as to minimize the emission of air contaminants shall be established.

8. This permit expires and the application is cancelled if construction has not begun within 24 months of the date of issuance of the permit.

9. On completion of construction of the device(s) for which this permit is issued, written notification of the fact is to be submitted to the Chief of the Air Division. The notification shall indicate whether the device(s) was constructed as proposed in the application. The device(s) shall not be operated until authorization to operate is granted by the Chief of the Air Division. Failure to notify the Chief of the Air Division of completion of construction and/or operation without authorization could result in revocation of this permit.

10. Submittal of other reports regarding monitoring records, fuel analyses, operating rates, and equipment malfunctions may be required as authorized in the Department's air pollution control rules and regulations. The Department may require stack emission testing at any time.

11. Additions and revisions to the conditions of this Permit will be made, if necessary, to ensure that the Department's air pollution control rules and regulations are not violated.

12. Nothing in this permit or conditions thereto shall negate any authority granted to the Air Division pursuant to the Alabama Environmental Management Act or regulations issued thereunder.

13. Any performance tests required shall be conducted and data reduced in accordance with the test methods and procedures contained in each specific permit condition unless the Director (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (2) approves the use of an equivalent method, or (3) approves the use of an alternative method, the results of which he has determined to be adequate for indicating whether a specific source is in compliance.

14. This permit is issued with the condition that, should obnoxious odors arising from the plant operations be verified by Air Division inspectors, measures to abate the odorous emissions shall be taken upon a determination by the Alabama Department of Environmental Management that these measures are technically and economically feasible.

15. The permittee shall not use as a defense in an enforcement action that maintaining compliance with conditions of this permit would have required halting or reducing the permitted activity.

16. The issuance of this permit does not convey any property rights of any sort, or any exclusive privilege.

17. The Atmore Plant shall comply with the requirements specified in proviso 17(a) through (c) of this permit.

    (a) Sulfur dioxide (SO_2) emissions shall not exceed 95 Tons/12 consecutive months.

    (b) Carbon monoxide (CO) emissions shall not exceed 95 Tons/12 consecutive months.

    (c) Volatile Organic Compounds (VOC) emissions shall not exceed 95 Tons/12 consecutive months.

18. All process gas streams containing 0.10 of a grain of hydrogen sulfide (H_2S) per Scf shall be burned to the extent that the ground level concentrations of hydrogen sulfide shall be less than twenty (20) parts per billion beyond plant property limits, averaged over a thirty (30) minute period.

19. Compliance with proviso 18 of this permit shall be demonstrated by complying with the requirements specified in proviso 19(a) through (d) of this permit.

(a) Except as provided for in proviso 19(a)(2), each process gas stream containing 0.10 grains of H_2S per scf shall be captured and sent through a closed vent system to the flare to be combusted.

(1) Compliance shall be demonstrated by conducting a process flow design evaluation of each site in conjunction with visible inspection of each.

(2) Except when vessels and equipment are being de-pressured and/or emptied and the reduced pressure will not allow flow of the gas to the flare, the venting to the atmosphere of any process gas stream shall not occur for a duration in excess of 15 continuous minutes.

(b) Maintaining the maximum H_2S feedrate to the flare at less than 500 lb/hr.

(c) Maintaining the presence of a spark or flame at the flare tip at all times a process gas stream may be sent to the flare.

(d) Testing each process gas stream that may be sent to the flare as specified in proviso 19 (d)(1) through (4) of this permit.

(1) Determine the H_2S content for the inlet sour gas stream, acid gas stream from the amine sweetening unit, and any other process gas stream that can be sent to the flare as follows:

(i) Capture one representative sample of the stream at a frequency of no less than once each month.

(ii) Analyze the sample collected utilizing the Tutwiler procedures in 40 CFR §60.648 of Subpart LLL, chromatographic analysis procedures found in ASTM E-260, the stain tube procedures found in GPA 2377-86 or those provided by the stain tube manufacturer, or other methods and procedures approved by the Department.

[Stream H_2S Content (H_2S Mole %)]

(2) Determine the Btu content, molecular weight, and volatile organic compound weight percent for the inlet sour gas stream, acid gas stream from the amine sweetening unit, and any other process gas stream that can be sent to the flare as follows:

(ii) Capture one representative sample of the stream at a frequency of no less than once each six months.

(iii) Analyze the sample utilizing the ASTM Analysis Method D1826-77, chromatographic analysis procedures found in 40 CFR Part 60 Appendix A, Method 18, Method 25A or other equivalent method and procedures.

[Stream Btu Content (BTU/Scf)]

[Stream VOC Content (VOC Wt %)]

[Stream M.W. (Mol Wt)]

(3) Provided multiple process streams can be sent to the flare and it is possible to capture a common stream whose contents would be representative of all the streams, that common stream may be used instead of the individual process streams.

(4) The tested components, testing methods and procedures, and testing frequency may be modified upon receipt of Departmental approval.

20. When possible and practical, a continuous metering system shall be utilized that is capable of continuously monitoring and recording the flow rate of each process gas stream vented to the flare prior to entry into the flare.

(a) The continuous measurement may be made with a single meter through which all of the sour gas steams flow, or with multiple meters through which an individual sour gas stream or multiple process gas streams flow.

(1) Calibration, maintenance and operation of metering system shall be performed in accordance to manufacturer's specification.

(b) Volumetric flow of sour gas streams that are not continuously measured shall be accounted for by utilizing special estimating methods (i.e. engineer estimates, material balance, computer simulation, special testing, etc).

21. The flare shall meet the opacity standards specified in proviso 21 (a) and (b) of this permit.

(a) Except for one 6-minute period during any 60-minute period, the flare shall not discharge into the atmosphere particulate that results in an opacity greater than 20%, as determined by a 6-minute average.age.

(b) At no time shall the flare discharge into the atmosphere particulate that results in an opacity greater than 40%, as determined by a 6-minute average.

22. Except when the facility is not manned by plant personnel or when process gas can not be sent to the flare, a daily visual inspection of the flare shall be conducted as specified in proviso 22 (a) through (d),.

(a) Visual inspections shall be made from a location that provides the best view of the flare, flare tip and/or flare pilot lights, or flare igniter.

(b) Provided that a spark or flame is not present at the flare tip when process gas can be sent to the flare, a record of the time, date, duration, and corrective actions taken for each incident shall be maintained

(c) Provided that visible emissions are observed from the flare, a visible emission observation shall be performed as specified in proviso 23 of this permit.

(d) A record of the time, date, and results of each visual inspection of the flare shall be maintained.

23. Provided that plant personnel observes visible emissions from the flare during the visual inspection of the flare and a process gas stream other than the pilot gas is being sent to the flare, a visible emission observation as specified in provisos 23 (a) through (d) shall be performed.

    (a) 40 CFR Part 60 Appendix A, Method 22 or other methods and procedures approved by the Department shall be utilized to perform the visible emission observations.

        (1) Visible emission observations utilizing Method 22 shall be conducted by an observer that is familiar with Method 22 methods and procedures.

        (2) Visible emissions that are observed utilizing Method 22 shall be deemed to have a reading in excess of 20% opacity and visible emission shall not be observed for more than one 6-minute period within a 60-minute observation period.

        (3) Visible emission observations shall be conducted during daylight hours.

    (b) The duration of each observation shall be no less than fifteen consecutive minutes.

    (c) Provided visible emission are observed in excess of the opacity standards, immediate corrective measures shall be undertaken to eliminate the visible emissions.

    (d) A record of the time, date, duration, and immediate corrective actions taken to eliminate visible emissions shall be maintained.

24. The following records shall be maintained and made available for inspection to demonstrate compliance with the requirements of proviso 17 of this permit.

    (a) 180 HP refrigeration compressor engine (E-01)

        (1) Engine Operating Hours

            [Engine Hours (Hours/Month)]

        (2) Engine Fuel Gas Usage

            [Engine Volume (Mscf/Month)]

        (3) Btu Content of Engine Fuel Gas

            [Engine Btu Content (Btu/scf)]

        (4) Engine's NO_X and CO Emissions shall be determined utilizing emission factors found in section 3.2 of AP 42 for four stroke rich burn (4SRB) Natural Gas-fired Reciprocating Engines and the equation below:

            (i) Engine Emissions (Lbs/Month) =

            [AP 42 Emission Factors (Lbs/MMBtu)] X [Engine Btu Content (Btu/Scf)] X {(MMBtu/ 10^6 Btu)} X [Engine Volume (Scf/Month)]

(ii) Engine Emissions (Tons/Month) =

[Engine Emissions (Lbs/Month)] X {1 Ton/ 2,000 Lbs}

(iii) Engine Emissions (Tons/12 Consecutive Months) =

Σ of Current Month Engine Emissions (Tons/Month) + Σ of Previous 11 Month Engine Emissions (Tons/Months)

(b) Process Flare (FLARE)

(1) Record of the daily visual inspection of the flare to demonstrate the presence or absence of visible emissions

~~(2)~~ Record of each-visible emission observation of the flare

(3) Record of daily visible inspections of the flare to demonstrate the presence or absence of a spark or flame at the flare tip

(4) Name of Process Gas Stream Burned in the Flare

(5) Volume of Gas Burned in the Flare

[Flared Volume (Mscf/Month)]

(6) Stream Heat Input (MMBtu/Month) =

[Flared Volume (Mscf/Month)] X [Stream Btu Content (Btu/Scf)] X {10^3 Scf/1 Mscf} X {1 MMBtu/ 10^6 Btu}

(7) Flare Heat Input (MMBtu/Month) =

Σ of Stream Heat Input (MMBtu/Month)

(8) Stream H_2S Feedrate (Lbs/Month) =

[Flared Volume (Mscf/Month)] X {1 Lb-mol/0.380 MScf of gas} X [Stream H_2S Content (H_2S Mol %) /100] X {34 Lbs of H_2S/ Lb-mol of H_2S}

(9) Flare H_2S Feedrate (Lbs/Month) =

Σ of Stream H_2S Feedrate (Lbs/Month)

(10) Flare Operating Hours

[Flare Hours (Hours/Month)]

(11) Flare H_2S Feedrate (Lbs/Hour) =

$$\frac{[\text{Flare } H_2S \text{ Feedrate (Lbs/Month)}]}{[\text{Flare Hours (Hours/Month)}]}$$

(12) Flare VOC emissions (Lbs/Month) =

[Flared Volume (Mscf/Month)] X {1 Lb-mole/0.380 MScf of gas} X [Stream VOC Content (VOC Wt %) /100] X [Stream MW (Mol Wt.)] X {0.02}

(Assuming a 98% destruction efficiency for the flare)

(13) Flare CO Emissions (Lbs/Month) =

[Flare Heat Input (MMBtu/Month)] X [(0.34 Lbs of CO/ MMBtu)]

(14) Flare SO_2 Emissions (Lbs/Month) =

[{1.689 Lbs/Mscf}] X [Stream H_2S Content (H_2S Mol %)] X [Flared Volume (Mscf/Month)]

(15) Flare Emissions (Tons/Month) =

[Flare Emissions (Lbs/Month)] X {1 Tons/ 2,000 Lbs}

(16) Flare Emissions (Tons/ 12 Consecutive Months) =

Σ of Current Month Flare Emissions (Tons/Month) + Σ of Previous 11 Month Flare Emissions (Tons/Months)

(c) Facility Wide Emissions NO_X, CO, VOC and SO_2 Emissions shall be determined as follow:

Facility Wide Emissions per pollutant (Tons/ 12 Consecutive Months) =

Flare Emissions (Tons/12 Consecutive Months) + Engine Emissions (Tons/12 Consecutive Months)

(d) Record of each occurrence of a deviation including the date, starting time, duration, and the cause and corrective actions taken shall be maintained and available for inspection.

25. The design capacity for the Atmore Plant shall be less than 2 long tons per day (Ltons/day) of hydrogen sulfide (H_2S) in the acid gas (expressed as sulfur).

26. An analysis demonstrating exemption from the control requirements of 40 CFR 60, Subpart LLL, "*Standards of Performance for Onshore Natural Gas Processing: SO_2 Emissions*" shall be kept and maintained for the life of the facility.

27. Periodic Monitoring Report (PMR) reports meeting the following requirements shall be submitted to the Department:

    (a) Reports shall cover a calendar semi-annual period and shall be submitted to the Department on the following reporting schedule:

Reporting Period	Submittal Date
January 1st through June 30th	*July 31st*
July 1st through December 31st	*January 31st*

    (b) Reports shall include any deviations from the permit requirements that occurred during the reporting period specified above.

28. All records, unless otherwise specified, shall be maintained in a permanent form suitable for inspection and shall be retained for at least two (2) years following the date of each occurrence, including the occurrence and duration of any startup, shutdown, or malfunction in the operation of the process equipment and any malfunction of the air pollution control equipment

29. All deviations from requirements within this permit shall be reported to the Department within 48 hours of the deviation or by the next work day while providing a statement with regards to the date, time, duration, cause and corrective actions taken to bring the sources back into compliance. A review and evaluation of this report shall be utilized in Departmental determination of whether or not a violation of a permit requirement or requirements occurred.

February 24, 2010
Draft Date

Alabama Department of Environmental Management

SYNTHETIC MINOR OPERATING PERMIT

PERMITTEE: AMERICAN MIDSTREAM, LLC

FACILITY NAME: ATMORE PLANT

LOCATION: ATMORE, (ESCAMBIA COUNTY), AL

PERMIT NUMBER	DESCRIPTION OF EQUIPMENT, ARTICLE OR DEVICE
502-0092-X002	**2.5 MMscf of gas/day Onshore Natural Gas Processing Plant**

In accordance with and subject to the provisions of the Alabama Air Pollution Control Act of 1971, as amended, Ala. Code §§22-28-1 to 22-28-23 (2006 Rplc. Vol. and 2007 Cum. Supp.) (the "AAPCA") and the Alabama Environmental Management Act, as amended, Ala. Code §§22-22A-1 to 22-22A-15 (2006 Rplc. Vol. and 2007 Cum. Supp.), and rules and regulations adopted there under, and subject further to the conditions set forth in this permit, the Permittee is hereby authorized to construct, install and use the equipment, device or other article described above.

ISSUANCE DATE: DRAFT February 24, 2010

Alabama Department of Environmental Management

American Midstream, LLC-Atmore Plant
ATMORE, ALABAMA
(PERMIT NO. 502-0092-X002)
PROVISOS

1. This permit is issued on the basis of Rules and Regulations existing on the date of issuance. In the event additional Rules and Regulations are adopted, it shall be the permit holder's responsibility to comply with such rules.

2. This permit is not transferable. Upon sale or legal transfer, the new owner or operator must apply for a permit within 30 days.

3. A new permit application must be made for new sources, replacements, alterations or design changes which may result in the issuance of, or an increase in the issuance of, air contaminants, or the use of which may eliminate or reduce or control the issuance of air contaminants.

4. When safe and practical, each point of emission will be provided with sampling ports, ladders, platforms, and other safety equipment to facilitate testing performed in accordance with procedures established by Part 60 of Title 40 of the Code of Federal Regulations, as the same may be amended or revised.

5. In case of shutdown of air pollution control equipment for scheduled maintenance for a period greater than **4 hour,** the intent to shut down shall be reported to the Air Division at least 24 hours prior to the planned shutdown, **unless accompanied by the immediate shutdown of the emission source.**

6. In the event there is a breakdown of equipment in such a manner as to cause increased emission of air contaminants for a period greater than **4 hour**, the person responsible for such equipment shall notify the Air Division within an additional 24 hours or next workday and provide a statement giving all pertinent facts, including the duration of the breakdown. The Air Division shall be notified when the breakdown has been corrected.

7. This process, including all air pollution control devices and capture systems for which this permit is issued, shall be maintained and operated at all times in a manner so as to minimize the emissions of air contaminants. Procedures for ensuring that the above equipment is properly operated and maintained so as to minimize the emission of air contaminants shall be established.

8. This permit expires and the application is cancelled if construction has not begun within 24 months of the date of issuance of the permit.

9. On completion of construction of the device(s) for which this permit is issued, written notification of the fact is to be submitted to the Chief of the Air Division. The notification shall indicate whether the device(s) was constructed as proposed in the application. The device(s) shall not be operated until authorization to operate is granted by the Chief of the Air Division. Failure to notify the Chief of the Air Division of completion of construction and/or operation without authorization could result in revocation of this permit.

10. Submittal of other reports regarding monitoring records, fuel analyses, operating rates, and equipment malfunctions may be required as authorized in the Department's air pollution control rules and regulations. The Department may require stack emission testing at any time.

11. Additions and revisions to the conditions of this Permit will be made, if necessary, to ensure that the Department's air pollution control rules and regulations are not violated.

12. Nothing in this permit or conditions thereto shall negate any authority granted to the Air Division pursuant to the Alabama Environmental Management Act or regulations issued thereunder.

13. Any performance tests required shall be conducted and data reduced in accordance with the test methods and procedures contained in each specific permit condition unless the Director (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (2) approves the use of an equivalent method, or (3) approves the use of an alternative method, the results of which he has determined to be adequate for indicating whether a specific source is in compliance.

14. This permit is issued with the condition that, should obnoxious odors arising from the plant operations be verified by Air Division inspectors, measures to abate the odorous emissions shall be taken upon a determination by the Alabama Department of Environmental Management that these measures are technically and economically feasible.

15. The permittee shall not use as a defense in an enforcement action that maintaining compliance with conditions of this permit would have required halting or reducing the permitted activity.

16. The issuance of this permit does not convey any property rights of any sort, or any exclusive privilege.

17. The Atmore Plant shall be subject to the requirements of 40 CFR 60, Subpart A "*General Provisions*", as specified in each applicable subpart.

18. Except as specified in 40 CFR §60.630(d), affected facilities at onshore natural gas processing plants that commences construction, reconstruction, or modification after January 20, 1984 are subject to the requirements found in 40 CFR 60, Subpart KKK "*Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants".*

19. Affected facilities under 40 CFR 60, Subpart KKK includes the following:

    (a) Each compressor in VOC service or in wet gas service,

    (b) The group of all equipment, except reciprocating compressors, within a process unit in VOC service or in wet gas service and any device or system required by this subpart as specified in proviso 19(b)(1) through (6):

(1) Pump

(2) Pressure Relief Device

(3) Open-ended Valve or line

(4) Valve

(5) Compressor

(6) Flange or Other Connector

20. Each compressor station, dehydration unit, sweetening unit, underground storage tank, field gas gathering system, or liquefied natural gas unit located at the Atmore Plant would also be covered under 40 CFR 60, Subpart KKK.

21. To demonstrate compliance with 40 CFR 60, Subpart KKK, within 180 days of initial start up, the Atmore Plant shall comply with the requirements found in 40 CFR 60, Subpart VV "*Equipment Leaks of VOC in the Synthetic Organic Chemical Manufacturing Industry"* as specified in proviso 21(a) or (b):

(a) Meet the emissions standards specified in proviso 21 (a)(1) through (10) of this permit:

(1) §60.482-1 (a), (b) and (d) of 40 CFR 60, Subpart VV for general standards.

(2) §60.482-2 of 40 CFR 60, Subpart VV for pumps in light liquid service, except as specified in §60.633(d) and (e) of 40 CFR 60 Subpart KKK.

(3) §60.482-3 of 40 CFR 60, Subpart VV for compressors, except as specified in §60.633(f) of 40 CFR 60, Subpart KKK.

(4) §60.482-4 of 40 CFR 60, Subpart VV for pressure relief devices in gas/vapor service, except as specified in §60.633 (b), (d), and (e) of 40 CFR 60, Subpart KKK.

(5) §60.482-6 of 40 CFR 60, Subpart VV for open-ended valves or lines.

(6) §60.482-7 of 40 CFR 60, Subpart VV for valves in gas/vapor service and in light liquid service, except as specified in §60.633(d) and (e) of 40 CFR 60, Subpart KKK.

(7) §60.482-8 of 40 CFR 60, Subpart VV for pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and connectors.

(8) §60.482-9 of 40 CFR 60, Subpart VV for delay of repair.

(9) §60.482-10 of 40 CFR 60, Subpart VV for closed vent systems and control devices.

(i) To comply with the control device requirements for flares subject to 40 CFR 60, Subpart KKK, the process flare shall meet the requirements specified in §60.18 of Subpart A.

(10) Equipment in vacuum service is excluded from the meeting the requirements in §60.482-2 through §60.482-10 of Subpart VV provided it is identified as required in §60.486(e)(6) Subpart VV.

(b) Meet the alternative means of compliance specified in §60.480(e) Subpart VV.

22. An owner or operator may apply for permission to use an alternative means of emission limitations as specified in §60.634 of Subpart KKK to satisfy the requirements of §60.482 through §60.487 of Subpart VV for an affected facility.

23. Compliance with the emissions standards for 40 CFR 60, Subpart KKK shall be demonstrated through the review of records and reports, review of performance test results, and inspection using the methods and procedures specified in §60.485 Subpart VV, except as specified in §60.633(h) of Subpart KKK.

(a) An owner or operator may use the provisions specified in §60.632(f) of Subpart KKK instead of those specified in §60.485(d) (1) of Subpart VV.

24. Emission monitoring shall be demonstrated by meeting the inspection and monitoring requirements specified in proviso 24 (a) and (b):

(a) §60.482-1 through §60.482-10 of Subpart VV, except that the following subparts specified in §60.633(d) and proviso 24 (a)(i) through (iii) of this permit shall be exempt from routine monitoring.

(i) §60.482-2(a)(1) of Subpart VV

(ii) §60.482-7(a) of Subpart VV

(iii) §60.633 (b)(1) of Subpart KKK

(b) Alternative standards for valves as specified in §60.483-1 or §60.483-2 of Subpart VV may be used to monitor valves.

25. To demonstrate compliance with the recordkeeping and reporting requirements, the owner or operator shall comply with §60.486 and §60.487 of Subpart VV and as specified in §60.633, §60.635, and §60.636 of Subpart KKK.

26. A Leak Detection and Repair (LDAR) summary report meeting the following requirements shall be submitted to the Department:

(a) The report shall cover a calendar semi-annual period and shall be submitted to the Department on the following reporting schedule:

Reporting Period	Submittal Date
January 1st through June 30th	*July 31st*
July 1st through December 31st	*January 31st*

(b) Reports shall include the following information:

(1) The initial semi-annual report shall be submitted beginning six months after the initial startup date and shall include the reporting requirements specified in 26(b)(1)(i) through (iii):

(i) §60.636(b) of Subpart KKK

(ii) §60.487(b)(1)-(4) of Subpart VV

(iii) Proviso 25(b)(2)(i) and (ii)

(2) All subsequent semi-annual reports shall include the reporting requirements found in proviso 26 (b)(2)(i) and (ii):

(i) §60.487(c)(2)(i) through (vi) of Subpart VV

(ii) §60.636(c) (1) and (2) of Subpart KKK

27. All deviations from requirements within this permit shall be reported to the Department within 48 hours of the deviation or by the next work day while providing a statement with regards to the date, time, duration, cause and corrective actions taken to bring the sources back into compliance. A review and evaluation of this report shall be utilized in Departmental determination of whether or not a violation of a permit requirement or requirements occurred.

February 24, 2010
Draft Date